TECHNICAL REVIEW DOCUMENT
for
RENEWAL / MODIFICATION TO OPERATING PERMIT 99OPBO223

International Business Machines
Boulder County
Source ID 0130006

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Revised July, August and October 2012

Reviewed by:

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I. Purpose:

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modification of the Operating Permit for International Business Machines. The current Operating Permit for this facility was issued on December 1, 2007 and expires on December 1, 2012. The source submitted a renewal application on November 22, 2011. Prior to submittal of the renewal application, the source submitted an application on September 30, 2011 requesting that the permit be modified to replace Boiler 2 with a proposed new boiler.

This document is designed for reference during review of the proposed permit by EPA, the public, other interested parties and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the renewal application submitted on November 22, 2011 and the modification application submitted on September 30, 2011, comments on the draft permit and technical review document submitted on August 27, 2012, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251596446069. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall

be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This source is classified as a provider of computer-related services under Standard Industrial Classification 7379. Specific significant emission units at this facility include the following: 36 emergency generators, 2 diesel fire water pumps, 3 cooling water towers (note that one tower is grandfathered from construction permit requirements) and 4 boilers fueled by natural gas, with diesel and/or jet fuel as back-up. In September 2011, the source submitted an application to install a new boiler that would be replacing one of the existing boilers. The replacement boiler is also fueled by natural gas, with diesel and/or jet fuel as back-up and is addressed in the permit. Appendix A of the permit includes a list of equipment that is considered insignificant at this facility.

This facility is located in Boulder at 6300 Diagonal Highway, in Boulder County. The Denver metro area, including Boulder, is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide. Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as nonattainment for ozone and is part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.1.

Rocky Mountain National Park and Eagle's Nest and Rawah National Wilderness Areas, all federal class I designated areas, are within 100 km of this facility. There are no affected states within 50 miles of this facility.

The summary of emissions that was presented in the Technical Review Document for the previous renewal permit has been modified to reflect the updated potential to emit (PTE) of both criteria and HAP pollutants due to changes that may have occurred in emission factors and/or emission limitations since the previous permit was issued. Emissions in (tons/yr) at the facility are as follows:

Emission Unit	Potential to Emit (tons/yr)						
	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPs
Nineteen (19) Emergency Generators and Two (2) Firewater Pumps (95BO557)	2	2	0.6	41.6	14.8	1.7	1.89E-2
Seven (7) Emergency Generators (00BO0630)	0.1	0.1	0.2	20.7	7.4	0.24	
Boilers 1 – 4 (94BO366)	3.1	3.1	1.1	50.6	40.3	2.0	6.84E-1
B011W Cooling Tower	1.86	1.86				0.15	3.91E-1*
B011 Cooling Tower	3.08	3.08				0.09	
B003 Cooling Tower	0.9	0.9				0.09	
Nine (9) Emergency Generators (07BO0730)	0.18	0.18	0.05	21.65	2.64	0.53	1.86E-2
Emergency Generator	0.03	0.025	0.002	3.0	0.65	0.13	2.49E-3

Emission Unit	Potential to Emit (tons/yr)						
	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPs
G041							
Proposed New Boiler	1.6	1.5	0.1	5.1	5.2	0.6	2.69E-1
Total	12.85	12.74	2.052	146.65	70.99	5.53	1.38

*Includes HAP emissions from all cooling towers, several of which are insignificant activities.

In the above table the criteria pollutant PTE is based on permitted emissions or the appropriate emission factors, design rate and 8760 hours per year of operation.

HAP emissions are based on permitted fuel consumption limits and the appropriate emission factors and/or design rate, the appropriate emission factors and 8760 hours per year of operation. The breakdown of individual HAP is shown on the table on page 17.

Although actual emissions may be less than permitted emissions, the source typically reports permitted emissions, rather than actual emissions, which is an acceptable practice. Therefore, actual emissions are not shown.

MACT Requirements

Hazardous air pollutant (HAP) emissions from this facility are below the major source level (10 tons/yr of any single HAP and 25 tons/yr of combined HAP). Although the facility is not a major source for HAPS, the EPA has been promulgating rules for area sources (sources that are not major), those requirements that could potentially apply to this facility are discussed below:

Paint Stripping and Miscellaneous Surface Coating at Area Sources (40 CFR Part 63 Subpart HHHHHH)

The final rules for paint stripping and miscellaneous surface coating were published in the Federal Register on January 9, 2008 and apply to area sources that perform paint stripping operations using methylene chloride, spray application of coatings to motor vehicles and mobile equipment and spray application of coatings that contain the target HAPS (chromium, lead, manganese, nickel or cadmium). As indicated in 40 CFR Part 63 § 63.11170(a)(2) and (3), spray applications (to motor vehicles and using coatings that contain the target HAPS) that meet the definition of facility maintenance are not subject to the requirements in this rule. The Division considers that any spray coatings of motor vehicles and mobile equipment and spray application of coatings that contain the target HAP at this facility would meet the definition of facility maintenance. The source indicated that none of the paint stripping chemicals used at the facility contain methylene chloride; therefore, the provisions in 40 CFR Part 63 Subpart HHHHHH do not apply.

Reciprocating Internal Combustion Engines (RICE) (40 CFR Part 63 Subpart ZZZZ)

Revisions were made to the RICE MACT (published in the Federal Register on January 18, 2008) to address engines (any size) located at area sources. Under the January

18, 2008 revisions only new engines (engines that commenced construction on or after June 12, 2006) were subject to requirements. New engines located at area sources meet the requirements of 40 CFR Part 63 Subpart ZZZZ by meeting the requirements in 40 CFR Part 60 Subpart IIII or JJJJ, as applicable. These requirements apply to a number of the engines addressed in this permit and will be included in the renewal permit.

Additional revisions to the RICE MACT were published in the Federal Register on March 3, 2010 and these revisions address existing (commenced construction prior to June 12, 2006) compression ignition engines at area sources but exempted emergency commercial, residential or institutional RICE located at area sources of HAP emissions from the requirements. In their August 27, 2012 comments on the draft permit, IBM noted an August 9, 2010 EPA Memo from Melanie King, "Guidance Regarding Definition of Residential, Commercial, and Institutional Emergency Stationary RICE in the NESHAP for Stationary RICE" which indicates that the IBM facility is considered a commercial facility. Therefore, the Division considers that the existing emergency generators are not subject to the RICE MACT requirements.

Industrial, Commercial and Institutional Boilers located at Area Sources (40 CFR Part 63 Subpart JJJJJJ)

The requirements in 40 CFR Part 63 Subpart JJJJJJ do not apply to gas fired boilers. The definition of gas-fired boiler in 40 CFR Part 63 Subpart JJJJJJ includes boilers that burn fuel oil during periods of natural gas curtailment, gas supply emergencies and periodic testing, as long as periodic testing does not exceed 48 hours in any calendar year. The Division considers that based on past operations for the boilers at this facility, that the units likely qualify as gas-fired boilers and as a result these requirements are unlikely to apply.

Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. None of the significant emission units at this facility are equipped with control devices; therefore, the CAM requirements do not apply to any of the emission units at this facility.

Greenhouse Gas Emissions

The potential-to-emit of greenhouse gas (GHG) emissions from this facility is less than 100,000 TPY CO_2e. Future modifications greater than 100,000 TPY CO_2e may be subject to regulation (Regulation No. 3, Part A, I.B.44).

III. Discussion of Modifications Made

Source Requested Modifications

September 30, 2011 Modification Request

The purpose of the September 30, 2011 modification application is to replace existing boiler No. 2 with a new boiler.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications "are not otherwise required by the Division to be processed as a significant modification" (Colorado Regulation No. 3, Part C, Section X.A.6).

The Division requires that "any change that causes a significant increase in emissions" be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.A.7.(a)). According to Part G of Regulation No. 3 (Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit. The Division interprets that a "significant increase in emissions" would be above the significant level as defined in Colorado Regulation No. 3, Part D, Section II.A.42. Requested emissions are based on the boiler running at design rate for 8,712 hrs/yr on natural gas and 48 hrs/yr on distillate fuel oil as a back-up (for a total operation time of 8760 hrs/yr). Requested emissions from this boiler are below the significant level as shown in the table below. In addition, emissions from the boiler running at design rate for 8760 hrs per year on either natural gas or distillate fuel only are also below the significant level. Therefore, since the potential to emit of the proposed new boiler is below the significant level the Division considers that this modification qualifies as a minor modification.

Pollutant	Emissions (tons/yr)			
	Requested[1]	Natural Gas – 8760 hrs/yr	Distillate Oil – 8760 hrs/yr	Significant Level[3]
PM[2]	1.55	1.53	5.91	25
PM_{10}[2]	1.54	1.53	3.62	15
$PM_{2.5}$[2]	1.53	1.53	1.88	10
SO_2	0.09	0.09	0.22	40
NO_X	5.09	5.01	20.03	40
CO	5.15	5.15	5.58	100
VOC	0.57	0.57	0.29	40

[1] Requested emissions are based on the unit running for 8712 hrs/yr on natural gas and 48 hrs/yr of distillate oil

[2] PM, PM_{10} and $PM_{2.5}$ emissions include filterable plus condensable.

[3]Major Stationary Source New Source Review (NSR) significant level defined in Colorado Regulation No. 3, Part D, Section II.A.42.

In addition, greenhouse gas emissions from this boiler are below 100,000 tons/year CO2e as indicated in the table below. Emissions were based on requested (design rate for 8712 hrs/hr on natural gas and 48 hrs/yr of distillate oil), natural gas only (design rate and 8760 hrs/yr of operation) and distillate oil only (design rate and 8760 hrs/yr of operation). The emission factors used were from 40 CFR Part 98 Tables C-1 and C-2.

CO_2e (tons/yr		
Requested	Natural Gas Only	Distillate Oil Only
16,775	16,740	23,936

In addition, the Division requires that "any change that is considered a modification under Title I of the Federal Act" be processed as a significant permit modification (Colorado Regulation No. 3, Part C, Section I.A.7.b). Part G of Regulation 3 Section I.L, revisions adopted July 15, 1993, Subsection I.G for modifications describes more specifically what constitutes a modification under Title I of the Federal Act and it indicates that a modification which triggers either Section 111 (new source performance standards (NSPS)) or 112 (national emission standards for hazardous air pollutant (NESHAP)) requirements is considered a Title I modification. The Division considers that modifications that trigger either NSPS or NESHAP requirements that are non-substantive requirements such as work practice standards or recordkeeping requirements can be processed as minor modifications. In addition, the Division considers that modifications that trigger either NSPS or NESHAP requirements that are already included in the Title V permit for another emission unit may be processed as a minor modification, since the specific requirements are already addressed in the permit.

In this case the proposed new boiler is subject to requirements in 40 CFR Part 60 Subpart Dc (NSPS). Boilers burning natural gas are subject to recordkeeping requirements only and boilers burning fuel oil are subject to SO_2 requirements (units burning distillate oil may monitor compliance with the SO_2 limits via fuel sampling). In this case, the Division considers that the NSPS Dc requirements for burning natural gas are non-substantive and although the SO_2 requirements may not be considered non-substantive the NSPS Dc requirements are already included in the Title V permit for Boiler No. 4. Therefore, since the NSPS requirements are non-substantive and/or already addressed in the permit, the Division considers that this modification can be processed as a minor modification. It should be noted that since the requested fuel oil consumption limit is based on the unit operating for 48 hours that the unit meets the definition of a gas-fired unit and is not subject to the requirements in 40 CFR Part 63 Subpart JJJJJJ. Note that the limit on hours operation when burning fuel oil has been included in the permit.

Modeling Analysis

With the exception of short-term NO_X, emissions are below the modeling thresholds in the Division's Colorado Modeling Guidelines May 20, 2011 Updated Tables as indicated in the table below; therefore, modeling is not warranted for this modification.

This boiler is replacing boiler No. 2, which is larger unit with higher estimated NO_X emissions. The proposed replacement boiler and stack will be in the same location as the existing boiler No. 2. In addition, in accordance with PS Memo 10-01 (see pages 18-19) the Division's Stationary Sources Program has indicated that for minor sources with requested emissions below 40 tons/yr of NO_X and SO_2 that a compliance demonstration is not required for the short-term (hourly) SO_2 and NO_2 national ambient air quality standard (NAAQS). Given that this unit is replacing a boiler with higher short-term NO_X emissions and that PS Memo 10-01 stipulates that a compliance demonstration for the hourly NO NAAQS is not required, a modeling analysis was not conducted.

Pollutant	Modeling Threshold		Project Emissions[1]	
	Annual	Short-Term	Annual	Short-Term
SO_2	40 tons/yr	0.46 lbs/hr	0.09 tons/yr	0.05 lbs/hr
NO_2	40 tons/yr	0.46 lbs/hr	5.09 tons/yr	4.57 lbs/hr
CO	100 tons/yr	23 lbs/hr	5.15 tons/yr	1.27 lbs/hr
PM_{10}	15 tons/yr	82 lbs/day	1.54 tons/yr	19.6 lbs/day
$PM_{2.5}$	5 tons/yr	11 lbs/day	1.53 tons/yr	10.2 lbs/day

[1]For annual emissions, project emissions are based on requested emissions (based on burning NG 8712 hrs/yr and DO 48 hrs/yr) and for short-term emissions, based on the worst case fuel.

The source's draft permit indicated that new boiler would be grouped and subject to the same fuel consumption and emission limitations as the existing boilers. However, in an effort to avoid "grouped" emission and fuel consumption limits, the Division is permitting this unit separately. The Division has not revised the throughput or emission limitations for the existing boilers.

Although permitted NO_X emissions from the existing boilers exceed the major stationary source nonattainment area new source review (NANSR) significance level (40 tons/yr), since there will be no physical change or change in the method of operation for the existing boilers the Division considers that the applicability test for these units is not required.

Proposed New Boiler:

Cleaver Brooks, Model No. 4WG-LN, Serial No. T2817-1-1, rated at 32.66 MMBtu/hr. The boiler will burn natural gas with distillate oil as back-up.

Provisions for the proposed new boiler have been included in "new" Section II.9 of the permit.

Applicable Requirements. The following requirements apply to the proposed new boiler:

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application (Reg 3, Part B, Section III.F.4.a.(i) thru (ii)).

- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (Reg 3, Part B, Section III.G.2).

- The permittee shall notify the Division, in writing, fifteen (15) days after startup (Reg 3, Part B, Section III.G.1).

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)

- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)

- Particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu, where FI is the fuel input in MMBtu/hr (Reg 1, Section III.A.1.b).

  For the permit, the design heat input of 32.66 MMBtu/hr was used in the above equation to calculated the particulate matter emission limits.

- SO_2 emissions shall not exceed 0.8 lb/MMBtu (Reg 1, Section VI.B.4.b.(i))

- Emission and fuel consumption limits.

  - NO_X emissions shall not exceed 5.1 tons/yr

  - CO emissions shall not exceed 5.2 tons/yr

    Requested emissions of PM, PM_{10}, $PM_{2.5}$, VOC and SO_2 emissions are below the APEN de minimis level and therefore limits for those pollutants are not included in the permit.

  - Natural gas consumption shall not exceed 284.5 MMscf/yr.

  - Distillate oil consumption shall not exceed 11,200 gal/yr.

  - Distillate oil shall not have a sulfur content greater than 15 ppm.

    The consumption limits are based on a natural gas heat content of 1000 Btu/scf and a distillate oil heat content of 140,000 Btu/gal. In the application the source indicated that the distillate fuel oil would meet the ultra low sulfur requirements (15 ppm S) and so this has been included in the permit as a requirement.

  - Hours operation on fuel oil shall not exceed 48 hours per calendar year.

    Since the source has requested the permit shield for the requirements in 40 CFR Part 63 Subpart JJJJJJ as non-applicable, the Division considers that the limit on hours of operation using fuel oil is warranted.

- RACT for NO_X, CO and PM_{10} shall be met through use of low NO_X burners (NO_X), good combustion practices (CO) and natural gas or distillate oil as fuel (PM_{10}) (Reg 3, Part B, Section III.D.2.a)

- RACT for VOC shall be considered good combustion practices (Reg 3, Part B, Section IIII.D.2.a and Reg 7, Section II.C.2)

- 40 CFR Part 60 Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units", as adopted by reference in Colorado Regulation No. 6, Part A, as follows:

- The boiler is also subject to the requirements in 40 CFR Part 60 Subpart A – New Source Performance Standards – General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A. The appropriate general provisions will be included in the permit.

  Requirements specific for Natural Gas

  - Notification requirements in § 60.48c(a)
  - Maintain records of fuel consumption per § 60.48c(g)
  - Maintain records for 2 years per § 60.48c(j)

  Requirements for Distillate Oil:

  - SO_2 limitations (sulfur content in fuel shall not exceed 0.5 percent by weight)
  - Opacity limitations.

    Note that since this unit will burn fuel oil with a sulfur content less than 0.5 weight percent it is exempt from the particulate matter standard in § 60.43c(e)(1), as specified in 60.43(e)(4)
  - Monitoring requirements for SO_2 and opacity (fuel supplier certification or shipment sampling and method 9 opacity observations)
  - Recordkeeping requirements – those specified for natural gas as well as the requirements in 60.48c(b), (c), (d), (e) and (f) which relate to opacity or SO_2 limitations.

- **State-only requirement.** The boiler is subject to Regulation No. 6 – Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, as follows:

  - Opacity of emissions shall not exceed 20%
  - Particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu, where FI = fuel input in MMBtu/hr
  - SO_2 emissions shall not exceed 0.8 lb/MMBtu

- The permit will include a requirement to remove and/or render the existing boiler No. 2 inoperable upon startup of the proposed new replacement boiler.

Although the provisions in 40 CFR Part 63 Subpart JJJJJJ are potentially applicable, since the requested distillate oil consumption limit is based on 48 hours and design rate and a limit of 48 hours of operation on fuel oil has been included in the permit, the Division considers that this unit qualifies as a gas-fired unit. As requested in the September 30, 2011 modification request, the requirements in 40 CFR Part 63 Subpart

JJJJJJ have been included in the permit shield for non-applicable requirements (Section III.1 of the permit).

Streamlining of Applicable Requirements

Opacity

The boiler is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operating conditions. The Reg 1 20% opacity requirement applies at all times, except for certain specific operational activities under which the Reg 1 30% opacity requirement applies. The boiler is also subject to the state-only Reg 6, Part B 20% opacity requirement and the NSPS Dc opacity requirement (20%/27%). The NSPS Dc opacity limit is not applicable during periods of startup, shutdown and malfunction in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.11(c) and Dc § 60.43c(d). Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20% / 30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. The NSPS opacity requirements are more stringent than the Reg 1 30% requirements under all the specific operating conditions except startup but are less stringent than the state-only Reg 6 requirements. The Reg 1 (20%/30%) opacity requirements are more stringent than the NSPS requirements during startup, shutdown and malfunction. Therefore, since no one opacity requirement is more stringent than the other at all times, all four opacity requirements are included in the operating permit. See the grid on page 20 for a clarified view on the opacity requirements and their relative stringency.

Since this boiler primarily burns natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements. Provisions will be included for those periods when distillate oil is used as fuel.

PM

The boiler is subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the quarterly excess emission reports, if required. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards

may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B particulate matter requirements do not apply during periods of startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

SO_2

This boiler is subject to the Reg 1 and Reg 6, Part B SO_2 requirements. The Reg 1 and 6, Part B SO_2 standards are the same, 0.80 lbs/MMBtu. The Reg 1 requirement applies at all times. As discussed above for PM, the Division considers that the Reg 6, Part B requirement does not apply during periods of startup, shutdown and malfunction. This boiler is also subject to an NSPS SO_2 limit on the fuel sulfur content of 0.5 weight percent (this equates to an SO_2 emission rate of 0.502 lb/MMBtu assuming a fuel density of 7.05 lb/gal and heat content of 140,000 Btu/gal). According to 40 CFR Part 60 Subpart Dc § 60.42c(i), the fuel sulfur limit applies at all times, including startup, shutdown and malfunction. In addition, the source has indicated that the fuel will meet ultra low sulfur requirements (15 ppm S) and the Division will include this requirement in the permit and this requirement will apply at all times. The ultra low sulfur fuel requirements are equivalent to an SO_2 emission rate of 1.51×10^{-3} lb/MMBtu (assuming a fuel density of 7.05 lb/gal and heat content of 140,000 Btu/gal). Since the ultra low sulfur diesel requirements are more stringent than the other SO_2 emission limitations, the Reg 1, Reg 6, Part B and NSPS Dc SO_2 emission limitations will be streamlined in favor of the ultra low sulfur fuel requirements.

Monitoring

NSPS Dc requires that records be kept for a period of 2 years, while Reg 3, Part C, Section V.C.6 requires that records be retained for five (5). Therefore, the NSPS recordkeeping requirement will be streamlined out of the permit.

Under NSPS Dc, sources that burn distillate oil and meet the fuel sulfur requirements (0.5 percent sulfur by weight) are required to either sample every shipment of fuel or to rely on vendor certifications. This is the monitoring that is currently required for the existing boilers (one of which is subject to NSPS Dc) that are subject to fuel sulfur limitations of 0.05 % by weight and will be required for the proposed new boiler.

NSPS Dc also requires that semi-annual reports be submitted for sources subject to the fuel sulfur limits, which include each 30-day average sulfur content of the fuel (if fuel sampling used) or the vendor certification with a certified statement indicating that the records of fuel supplier certifications represent all the fuel combusted during the reporting period. The Title V permit requires that semi-annual monitoring and permit deviation reports be submitted, which require the Responsible Official to certify that the

information in the reports is “true, accurate and complete”. The Division considers that since these semi-annual reports will cover the ultra low sulfur fuel requirements that will be included for the proposed new boiler, that the NSPS Dc semi-annual reporting requirements are essentially satisfied.

As a result the sulfur monitoring requirements in NSPS Dc will be streamlined in favor of the monitoring that will be included for the ultra low sulfur fuel requirements.

Emission Factors: Approval of emission factors is necessary to monitor compliance with the permit limitations. Emissions from this project are based on the following emission factors:

Pollutant	Emission Factor (lb/MMBtu) Natural Gas (NG)	Distillate Oil (DO)	Emission Factor Source
PM^1	0.011	0.041	Manufacturer for filterable PM. Condensable PM from AP-42 Section 1.4 (dated 7/98), Table 1.4-2 for NG and Section 1.3 (dated 5/10), Table 1.3-2. For NG, it was assumed that $PM=PM_{10}= PM_{2.5}$. For DO, the breakdown of filterable PM to PM_{10} and $PM_{2.5}$ was per AP-42, Section 1.3, Table 1.3-6.
PM_{10}^1	0.011	0.025	
$PM_{2.5}^1$	0.011	0.013	
SO_2	0.0006	1.54×10^{-3}	Manufacturer. For DO, manufacturer’s emission factor was adjusted by ratio of weight percent sulfur (0.0015%/0.2%)
NO_X	0.035	0.140	Manufacturer
CO	0.036	0.039	Manufacturer
VOC	0.004	0.002	Manufacturer

[1]PM, PM_{10} and $PM_{2.5}$ includes both filterable and condensable portions.

Note that since emissions of PM, PM_{10}, $PM_{2.5}$, VOC and SO_2 were below the APEN de minimis levels, emission limitations for these pollutants were not included in the permit.

Monitoring Plan: The source will be required to monitor compliance with the emission and fuel use limits by recording fuel consumption and calculating emissions monthly. Compliance with the Reg 1 particulate matter limit will be presumed provided natural gas and ultra low sulfur distillate oil are used as fuel. Sampling of each shipment of fuel will be required to monitor compliance with the fuel sulfur limits. In lieu of sampling, vendor receipts may be used to verify compliance with the fuel sulfur limits. In the absence of credible evidence to the contrary compliance with the opacity limits will be presumed whenever natural gas is used as fuel. Periodic Method 9 observations will be required for the unit when burning distillate oil.

November 22, 2011 Renewal Application

The following changes were requested in the renewal application submitted on November 22, 2011.

<u>Plot Plan</u>

A new plot plan was included in the renewal application but specific equipment was not noted on the revised plan. Therefore, the revised plot plan was not included in the permit.

Remove Emergency Generator G028

This source indicated that this unit is no longer at the facility and requested that references to this unit be removed throughput the permit. Specifically the following changes were made:

- The description in Section I, Condition 1.1 of the permit was revised to reduce the number of emergency generators by 1.
- Generator G028 was removed from the summary table in Section I, Condition 6.1, and the table and text in Section I, Condition 6.3.
- References to Generator G028 were removed from Section II, Condition 2. This includes the title for the summary table and tables within Conditions 2.1 and 2.3.
- Removed references to Generator G028 from the permit shield for non-applicable requirements (Section III.1, table).

Generator G041

The source requested that the startup date and serial number for G041 be included in the permit. Specifically the following changes were made to the permit based on this request:

- The serial number and startup date for G041 were added to the summary table in Section I, Condition 6.1.
- The serial number for G041 was added to the tables in Appendices B and C.

Insignificant Activities List (Appendix A)

The source requested that the insignificant activity list be revised to update the size of some diesel storage tanks, to update the number of some tanks and to include new entries for Buildings 009N, 020W (two (2) 1,000 gal tanks) and 021. The insignificant activity list in Appendix A was revised as requested.

Permit Shield

The source requested the permit shield from the provisions of 40 CFR Part 63 Subpart JJJJJJ, “National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers”, for Boilers B001 through B003. The justification for this request is that the boilers are natural gas fired and that periodic testing with liquid fuel does not exceed 48 hours per calendar year. Boilers B001 through B004 are subject to a common liquid fuel consumption limit of 400,000 gallons per year. Based on the design heat input rates of the boilers (in MMBtu/hr) and an

assumed distillate oil heat content of 140,000 Btu/gal, these units can run for more than 48 hours per year based on the permitted fuel oil limit. Therefore, the Division will not include 40 CFR Part 63 Subpart JJJJJJ in the permit shield for non-applicable requirements for the existing boilers. Based on past operations of these units, it is expected that the units will not burn fuel oil for more than 48 hours in a calendar year and thus not be subject to the requirements 40 CFR Part 63 Subpart JJJJJJ. Therefore, the Division included language in Section II.3 of the permit indicating that if these units burn liquid fuel for more than 48 hours in any calendar year for periodic testing that the provisions in 40 CFR Part 63 Subpart JJJJJJ will apply.

Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments on other permits, to the International Business Machines Operating Permit with the source's requested modifications. These changes are as follows:

Section I – General Activities and Summary

- Condition 1.4 was revised to remove Section IV, Condition 3.d as a state-only requirement, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

Section II.3 – Existing Boilers B001 through B004

- The Reg 1 SO_2 emission limitations were removed (Condition 3.3). The fuel sulfur limitation in Condition 3.4 is more stringent than the Reg 1 SO_2 limitations, therefore they are included in the permit shield for streamlined conditions (Section III.3)

- Clarified that the NSPS Dc opacity requirement (Condition 3.7.2) only applies to boiler 4 when burning distillate fuel (diesel/jet fuel).

- The opacity monitoring language in Condition 3.7.6.2 was modified to require annual, rather than quarterly method 9 observations. Since the permitted fuel limits for these boiler allow limited operation on distillate oil (at design rate with all boilers except Boiler 2 running, the units can run for ~310 hours per year) less frequent monitoring is acceptable. In addition, other language changes have been made to the opacity monitoring requirements in order to simplify them.

- Revisions to NSPS Dc were published in the Federal Register on January 28, 2009 to add monitoring provisions for the opacity requirements. Subsequent

revisions to NSPS Dc were made on January 20, 2011 to include timelines for conducting the opacity monitoring. Since these requirements apply to Boiler 4, the opacity monitoring provisions have been included in the permit. The January 20, 2011 revisions also include reporting requirements and these have also been included in the permit.

Note that since fuel oil was not burned in boiler 4 in 2010 and 2011 the permit specifies that the performance test shall be conducted within 60 days of burning fuel oil (the January 20, 2011 revisions specify that the test be conducted by April 29, 2011). It is not the Division's position that boiler 4 be operated on fuel oil solely to conduct an opacity performance test.

- Language was added to indicate if the boilers run more than 48 hours per calendar year on distillate oil for testing, that the provisions in 40 CFR Part 63 Subpart JJJJJJJ apply.

Emergency Generator Requirements – Sections II.1, 2, 7 & 8

- The opacity monitoring requirements were simplified. Frequency for method 9 observations is still annual but there are provisions for more observations if an engine is operated for more than 250 hrs/yr.

- Removed Conditions 7.9 through 7.11 (commence construction, startup notice and compliance certification) since these requirements have been completed.

Section II.5 – 40 CFR Part 60 Subpart IIII Requirements

- At the request of the inspector, the section headers for the NSPS requirements have been simplified (they no longer reflect the direct section headers indicated in the regulation).

- Condition 5.1.3 was removed since these fuel requirements no longer apply (they have been replaced by the requirements in Condition 5.1.4).

- The language in Condition 5.1.3 indicating that the engine's day tank be sampled and analyzed within 60 days of permit issuance has been removed. It has been more than 60 days since the permit was last issued (12/28/10) and more than 60 days since the last engine subject to these requirements commenced operation (July 2011), so this requirement had been completed.

- Revisions were made to the provisions in Subpart IIII (published in the June 28, 2011 Federal Register) and these revisions have been reflected in the permit language. Those requirements revised include 5.1.2, 5.1.5 and conditions under § 60.4211.

Section II.6 – NSPS General Provisions

- At the request of the inspector, language was added to indicate which units are subject to these requirements.

40 CFR Part 63 Subpart ZZZZ Requirements – Sections II.2, II.7, II.8 and III.1

Engines that commenced construction or reconstruction on or after June 12, 2006 at area sources are considered "new" or "reconstructed" and "new" and "reconstructed" engines located at area sources meet the requirements in 40 CFR Part 63 Subpart ZZZZ by meeting the requirements in 40 CFR Part 60 Subpart IIII.

In accordance with the provisions in § 63.6590(b)(3)(vii), existing (commenced construction or reconstruction prior to June 12, 2006) commercial emergency stationary RICE located at an area source of HAP emissions do not have to meet the requirements in Subparts A and ZZZZ, including the initial notification requirements.

Engines G029 through G041 are considered new engines and the appropriate MACT ZZZZ requirements will be included in Sections II.2, II.7 and II.8 of the permit for these engines.

Engines G001 through G012 and G015 through G027 are considered existing engines. Note that although the table in Section I, Condition 6.1 says that G023 was first placed in service in 2009, the engine was manufactured in July 2001. The definition of commenced construction in 40 CFR Part 63 Subpart ZZZZ is based on "on-site" fabrication or installation and it specifically excludes the removal of equipment from an existing location and reinstallation at a new location. Specifically it means that engines that are relocated are not considered to be "new" engines. Therefore, since G023 was manufactured in 2001, the Division presumes that this engine was operating in some other location and was merely relocated to the IBM facility; hence it qualifies as an existing engine. Since engines G001 through G012 and G015 through G027 are existing emergency commercial stationary RICE located at an area source of HAP emissions they are not subject to the requirements in 40 CFR Part 63 Subpart ZZZZ. At the request of IBM in their August 27, 2012 comments on the draft permit, the requirements in 40 CFR Part 63 Subpart ZZZZ have been included in the permit shield for non-applicable requirements for the existing emergency engines.

Section IV – General Conditions

- Changed the version date.
- The paragraph in Condition 3.d indicating that the requirements are state-only has been removed, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

Appendices

- Updated the facility plot plan in Appendix A.
- Changed the Division contact for submittal of reports in Appendix D.
- Cleared the information from the table in Appendix F.

IBM Facility Wide HAP Emissions

Pollutant	Hazardous Air Pollutant Emissions (tons/yr)						
	Boilers	Emergency Generators[1]	Nine (9) Emergency Generators[2]	Emergency Generator G041	Cooling Water Towers[3]	Proposed New Boiler	Total
Acetaldehyde		6.57E-04	2.75E-04	3.68E-05			9.69E-04
Acrolein		1.35E-04	8.60E-05	1.15E-05			2.33E-04
Benzene	7.78E-04	9.32E-03	8.47E-03	1.13E-03		3.00E-04	2.00E-02
Chloroform					3.91E-01		3.91E-01
Dichlorobenzene	4.20E-04					1.71E-04	5.91E-04
Formaldehyde	3.29E-02	1.47E-03	8.61E-04	1.15E-04		1.09E-02	4.62E-02
Hexane	6.30E-01					2.56E-01	8.86E-01
Naphthalene	2.26E-04	1.53E-03	1.42E-03	1.90E-04		6.33E-06	3.37E-03
Nickel	1.76E-02					7.72E-04	1.84E-02
Toluene	2.43E-03	3.41E-03	3.07E-03	4.10E-04		5.18E-04	9.84E-03
Trichloroethane (TCA)	4.72E-05					1.32E-06	6.04E-05
Xylenes		2.34E-03	2.11E-03	2.82E-04			4.73E-03
POH			2.31E-03	3.10E-04			2.62E-03
Total	6.84E-01	1.89E-02	1.86E-02	2.49E-03	3.91E-01	2.69E-01	1.38E+00

[1] addressed in construction permits 95BO557 and 00BO0630
[2] addressed in construction permit 07BO0730
[3] Includes all cooling water towers, some of which are APEN exempt.

COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Stationary Sources Program / Air Pollution Control Division

INTER-OFFICE COMMUNICATION

PS Memo 10-01

TO: Stationary Sources Staff, Local Agencies, Regulated Community

FROM: Kirsten King and Roland C. Hea

DATE: September 20, 2010

RE: Permit Modeling Requirements for the 1-Hour NO_2 and SO_2 NAAQS

The Division is establishing this guidance for use by minor stationary sources of nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) in evaluating whether modeling is necessary for permitting purposes to determine whether a permit applicant's emissions will comply with the new 1-hour NO_2 and/or the new 1-hour SO_2 National Ambient Air Quality Standard (NAAQS). The United States Environmental Protection Agency (EPA) published implementation guidance on June 28, 2010 and August 23, 2010 regarding demonstrating compliance with the new standards for Prevention of Significant Deterioration (PSD) sources.[1] The Division finds it useful to publish this supplemental state guidance to ensure that minor sources are addressed in a manner consistent with the EPA guidance for PSD sources.

Under federal rules, an ambient air quality impact analysis is required for each pollutant that a PSD source has the potential to emit in significant amounts. Such analysis includes modeling. The metric used by EPA to measure significant amounts is the significant emissions rate (SER). Federal rules currently define the SER for NO_X and SO_2 as 40 tons per year (tpy). (40 CFR 52.21(b)(23)(i); 40 CFR 51.166(b)(23)(i)). EPA recently evaluated and decided to apply on an interim basis the 40 tpy SER to major source permitting compliance demonstrations for the hourly NO_2 and SO_2 standards. EPA concludes and states that an ambient air quality impact analysis is not necessary for PSD sources with projected NO_2 or SO_2 emissions rates below the SER. (Wood Memoranda at p.11 and p.4)

[1] See June 28, 2010, Anna Marie Wood, Acting Director, Air Quality Policy Division, Office of Air Quality Planning and Standards Memorandum "General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level" and August 23, 2010 Memorandum "General Guidance for Implementing the 1-hour SO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour SO_2 Significant Impact Level" ("Wood Memoranda").

The Division has evaluated EPA's rationale for establishing NO_2 and SO_2 SERs for modeling the 1-hour NO_2 and SO_2 standards. The Wood Memoranda guidance set forth EPA's reasoning that its SER for SO_2 (a pollutant with shorter-term 3-hour and 24-hour averaging times) is 40 tpy, and, for this pollutant, ambient air quality impact analyses have not been necessary at levels below the SER. EPA has concluded that this reasoning applies to the one-hour NO_2 and SO_2 standards on an interim basis. EPA states it intends to conduct an evaluation of screening tools available to permitting agencies. In the interim, it recommends the continued use of the existing SER for NO_x and SO_2 emissions with respect to the 1-hour NO_2 and SO_2 standards, and thus ambient air quality impact analyses are not necessary for either NO_2 or SO_2 emissions below the 40 tpy SER.

EPA's Wood Memoranda guidance address PSD sources. The Division believes that the same principles apply to minor sources, in part, to ensure consistency of treatment in permitting and to ensure that it is not imposing different requirements on minor sources than those to which PSD sources are subject. The Division is aware of no factual basis to impose more stringent requirements on minor sources than EPA would impose on the largest air pollution sources. Therefore, the Division will apply EPA's SERs for NO_X and SO_2 to the 1-hour NO_2 and 1-hour SO_2 standards for all stationary source permitting activities, including determining when ambient air quality impact analyses are necessary for permitting, pending the consideration of any further guidance issued by EPA on this subject.

Opacity Streamlining Grid

Reqmt Source	Normal	Start-up	Shutdown	Malfunction	Fire Building	Cleaning of Fire Boxes	Soot Blowing	Process Modifications	Adjustment of Control Equipment
Reg 1 Sections II.A.1 & 4	20%	30% with one 6 minute interval in excess of 30% per hour	20%	20 %	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30 % with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour
Reg 6, Part B, Section II.C.3 **- State Only**	20%	No standard[1]	No standard[1]	No standard[1]	**20%**	**20%**	**20%**	**20%**	**20%**
NSPS Subpart Dc (40 CFR § 60.43c(c)) **Only applies when burning distillate oil.**	20% with one 6 minute interval of 27% per hour	No standard[1]	No standard[1]	No standard[1]	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20% with one 6 minute interval of 27% per hour	20 % with one 6 minute interval of 27% per hour

* Shaded regions are the most stringent **Federal** requirements

** Values in **bold** are the most stringent **State-only** requirements however **federal** requirements cannot be streamlined out of the permit due to more stringent **state-only** requirements